Oil and Gas News Briefs
Compiled by Larry Persily
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U.S. to take top spot among world LNG exporters next year

(Natural Gas Intelligence; Dec. 3) - The U.S. will become the world's largest liquefied natural gas exporter in 2022 once the sixth train at Cheniere Energy's Sabine Pass terminal and Venture Global's new Calcasieu Pass facility come online in Louisiana next year, according to the Energy Information Administration. At that point, peak U.S. LNG production capacity would hit 13.9 billion cubic feet per day, surpassing Australia (11.4 bcf) and Qatar (10 bcf), which are currently the world's top exporters, EIA said.

It was only four years after the first LNG exports from the Lower 48 states in 2016 that the U.S. became the world's third-largest exporter. Sabine Pass Train 6 and Calcasieu Pass LNG are currently being commissioned. Those processes, combined with soaring international demand for U.S. LNG amid a global supply crunch, recently pushed feed gas deliveries to U.S. export terminals to a record 12.43 bcf a day on Nov. 26.

Train 6 at Sabine Pass produced its first LNG late last month and is expected to be completed in the first quarter of 2022. Calcasieu Pass is expected to enter service next year and become the seventh U.S. export terminal in operation. Once Golden Pass LNG comes online in 2024, which is currently under construction in Sabine Pass, Texas, peak U.S. LNG export capacity would hit 16.3 bcf per day, or more than 25% of the world' production capacity. Federal regulators have approved an additional 10 new LNG export projects and capacity expansions at existing terminals.

U.S. sets another record for gas deliveries to LNG export terminals

(S&P Global Platts; Dec. 2) - Natural gas deliveries to U.S. LNG export terminals surged to record levels in the waning days of November, topping 12 billion cubic feet per day as strong global demand continued to incentivize operators to run their facilities at full bore. Total feed gas deliveries to the six major operating U.S. LNG export facilities pushed above 12 bcf per day Nov. 26. Average daily flows for November exceeded 11 bcf. At 12 bcf a day, the U.S. could be filling more than three standard-size LNG carriers a day.

Part of the uptick was because of commissioning work on a sixth liquefaction train at Cheniere Energy's Sabine Pass LNG terminal in Louisiana. The company said the train produced its first LNG on Nov. 23. High global gas prices were a key driver. The European benchmark day-ahead contract reached an all-time high of $39.51 per million Btu on Oct. 5, while the S&P Global Platts Japan Korea Marker spot Asian LNG price hit a record high of $56.33 on Oct. 6. Prices have fallen since then, but they remain several times higher than prices in the U.S. and continue to encourage U.S. LNG exports.

In the U.S., robust LNG exports in recent months have attracted criticism from an industrial manufacturers trade group long opposed to the gas exports. The group has mounted a renewed effort to convince the U.S. Department of Energy to limit exports to avoid winter price spikes and domestic supply shortages. However, the leading U.S. LNG trade group argued that curbing exports could upend gas markets and undermine billions of dollars worth of infrastructure investments.

LNG developer files for another project in Louisiana

(Natural Gas World; Dec. 2) – LNG developer Venture Global on Dec. 2 filed a federal application to construct and operate a new LNG export terminal in Louisiana. Venture Global said it wants to build the $10 billion facility near the Calcasieu Ship Channel. Dubbed CP2, so named for its location in Cameron Parish and adjacent to Venture's nearly complete Calcasieu Pass facility, the company expects the new facility would have a nameplate liquefaction capacity of 20 million tonnes per year of LNG from nine small-scale liquefaction blocks in each of two 10-million-tonne phases.

In its filing with the Federal Energy Regulatory Commission, Venture Global said the CP2 terminal would feature units to remove carbon dioxide and hydrogen sulfide from the plant's emissions. Additional facilities associated with the terminal could sequester much of the CO_2. The first phase of the plant could support four LNG cargoes per week.

In its FERC application, Venture Global said construction on the first phase could begin following the receipt of all regulatory approvals, expected in the second quarter of 2023, and would continue for about three years. Timing for the second phase would depend on market demand and off-take agreements, but could begin as early as 12 months after the start of Phase 1 construction.

Canceled LNG project raises questions for future FERC decisions

(EnergyWire; Dec. 2) - The announcement by Calgary-based Pembina Pipeline that it is abandoning its plans to build a liquefied natural gas export terminal in Coos Bay, Oregon, adds to a growing debate about the role of natural gas at a time of high prices and as industry groups are pressuring the Biden administration to clarify exactly how LNG exports fit into its broader climate agenda. It also may influence the Federal Energy Regulatory Commission's ongoing review of how it approves gas projects.

The company had put the export project on an indefinite hold in April after failing to get key state and federal approvals, and on Dec. 1 told FERC it was giving up on the $10 billion project. Initially proposed in 2007 by a previous developer, Jordan Cove has been vigorously contested by nearby property owners, environmental groups, Indigenous communities and state officials. The proposal has also been a symbol of FERC's alleged deference to industry in its assessments of natural gas projects.

When FERC approved the latest iteration of the project in a 3-1 vote last year, critics — including then-commissioner and now Chair Richard Glick, who dissented — accused the majority on the commission of ignoring signs that the project's benefits didn't outweigh the environmental costs. Now that it has been canceled, the Jordan Cove case provides additional evidence that FERC must scrutinize natural gas proposals and fully consider whether they are in the public interest, said Gillian Giannetti, an attorney at the Natural Resources Defense Council's Sustainable FERC Project.

OPEC+ sticks with production plan despite new COVID variant

(The Wall Street Journal; Dec. 2) - OPEC and a group of Russia-led oil producers on Dec. 2 agreed to continue pumping more crude, sticking to their long-term plan despite new worries over demand raised by the Omicron coronavirus variant. The Organization of the Petroleum Exporting Countries and allied producers led by Russia — which together call themselves OPEC+ — said they would raise their collective production by another 400,000 barrels a day in January. The group agreed earlier this year to boost output in such increments each month until production reaches pre-pandemic levels.

Outside analysts, however, have questioned whether the group can pump as much as it says it will. With production in Russia and many African countries participating in the pact reaching peak levels, the group may only be able to increase output by about 250,000 barrels a day, said Christyan Malek, head of oil and gas research at JPMorgan. Most of that will come from OPEC producers in the Persian Gulf, he said. Still, he said, the move "shows OPEC+'s confidence that the impact of Omicron will be short-lived."

But some traders worry Omicron could upend expectations that most of the world is gradually returning to normalcy. Regardless, the OPEC+ decision to keep raising production in January added to supply pressure on oil markets, said John Kilduff, a partner at energy hedge fund Again Capital, who said he thinks benchmark U.S. crude prices will fall to between $58 to $62 a barrel.

Russia, Saudi Arabia can balance budgets with lower oil prices

(S&P Global Platts; Dec. 2) - Lower budgetary break-even oil prices may help Russia and OPEC's core Persian Gulf producers align their production policy in 2022 despite lingering concerns in Moscow about the global oil demand outlook and availability of spare production capacity, according to analysts. S&P Global Platts Analytics estimates

Saudi Arabia's fiscal break-even price at $79 per barrel in 2021, down from $87 in 2020. It estimates Russia's break-even price at $69 for 2021, also down from $76 in 2020, but well above the pre-pandemic average of $52 in 2018-19.

"The narrowing of the two OPEC+ leaders' respective fiscal (budgetary) requirements likely portends greater cohesion on production strategy than would have been the case even in 2019, when the gap exceeded $30," said Paul Sheldon, chief geopolitical adviser for Platts Analytics. In the past, Russia has frequently pushed for increases to its production quota, and retains a strong economic position within the OPEC+ alliance, making it comparatively resilient to oil-price shocks.

"Russia still feels much more comfortable from a macroeconomic perspective than most of its peers within OPEC+. … Russia's 2020 budget deficit amounted to 4% of GDP, while in Saudi Arabia it exceeded 11%," said George Voloshin, head of the Paris branch of Aperio Intelligence. A key part of Russia's resilience is a fiscal rule adopted in 2017 that has softened the impact of oil-price fluctuations on its economy and budget. It uses a baseline price assumption. If crude is above this level, revenues are diverted to the National Wealth Fund. If they are below, the government can draw from the fund.

Nigeria, Iraq boost oil production above OPEC limit

(Bloomberg; Dec. 2) - OPEC nations added more oil in November than required by their plans to restore halted production, as one member overcame nagging disruptions and another flouted its limit. The Organization of Petroleum Exporting Countries added 350,000 barrels a day last month, almost 40% more than specified in its schedule for reviving supplies shuttered during the pandemic, according to a Bloomberg survey. The boost was driven partly by a recovery in Nigeria, and also by more production in Iraq.

In recent months the cartel has faced a different issue: Fulfilling its promise to restore suspended production sufficiently to soothe runaway fuel prices and aggressive inflation among its biggest customers. In November, the organization got a better grip on the problem. Output among its 13 members rose by the most since July to reach 28 million barrels a day, according to the survey. The figures based on ship-tracking data, information from officials and estimates from consultants including and JBC Energy.

Iraq made the biggest gain, boosting output by 100,000 barrels a day to 4.28 million — considerably above its agreed limit. Baghdad has long chafed against OPEC output restrictions, contending that it deserves to make up for decades of revenue losses from sanctions and conflict. Nigeria delivered the best comeback, adding 90,000 barrels a day to 1.53 million. Shell announced Nov. 27 it would be able to resume cargoes of the nation’s Bonny Light crude after a month-long disruption caused by a pipeline outage.

Russia’s oil production continues to grow

(S&P Global Platts; Dec. 2) - Russia averaged about 10.89 million barrels per day of crude and condensate in November, according to data released by the Central Dispatching Unit of the Russian Energy Ministry on Dec. 2. Russian production volumes have risen over the past year in line with increases to OPEC+ quotas. The group has been relaxing production cuts in response to growing global demand and recovering markets amid vaccine rollouts and governments easing lockdowns.

Russia’s daily average output was up from 10.85 million barrels per day in October and 10.03 million in November 2020. Russian production data doesn't include a breakdown for crude and condensate. Condensate usually accounts for about 8% of Russia 's overall output. The country exports more than 40% of its oil production.

Goldman Sachs sees possibilities to exceed $85 forecast in 2023

(Bloomberg; Dec. 2) - Oil prices are primed for gains as the decision by OPEC+ to proceed with planned production increases won’t derail an ongoing structural bull market, according to analysts at Goldman Sachs. The investment bank sees “very clear upside risks” to exceeding its forecast for Brent oil to average $85 a barrel in 2023.

U.S. shale producers will be cautious in their spending plans for 2022 because of previous low prices, holding back on future production. And while there’s slower growth in shale production, OPEC’s spare capacity will be reduced more quickly than if the group had decided to pause its monthly output increases, Goldman said. That’s especially if there is no deal to allow more Iranian oil on the market next year.

Recent price declines, amid concern that the Omicron variant of coronavirus will damage global oil demand, have been overdone and current prices offer “compelling opportunities” to reinvest, the Goldman analysts said. In the short term, the oil market needs more information on the virulence of the latest coronavirus variant for oil prices to recover further, and may need more evidence of a tight market to lift oil prices above $80, Goldman said.

Shell decides not to invest in North Sea oil prospect

(The New York Times; Dec. 2) – Shell said Dec. 2 that it had decided not to invest in a British oil development off the coast of Scotland that has become a test of the U.K. government’s environmental credentials. The field, known as Cambo, is in deep water northwest of the Shetland Islands. It is seen as a bellwether for the future of Britain’s declining but still large North Sea oil industry.

The British government is considering whether to approve the project, which environmental groups and some politicians have said should be rejected because it would produce carbon dioxide emissions responsible for climate change. Shell, which owns 30% of Cambo, said it had "concluded the economic case for investment in this project is not strong enough at this time." The company also said there was "potential for delays," apparently referring to the possibility that the drilling would draw protests from environmental groups and possibly legal actions trying to stop it.

Shell's decision to decline to invest in developing Cambo is a serious blow to the project. Siccar Point Energy, a private equity-backed firm that is Cambo's main owner and developer, said that while "disappointed" by Shell's decision, it remained "confident about the qualities" of the project. Siccar Point has said that it plans to invest $2.6 billion in Cambo and that it has already spent $190 million in the four years since it acquired the rights to the field, which was discovered in 2002.

Japan may not be ready to move away too fast from fossil fuels

(Bloomberg; Dec. 2) - It's been less than a month since world leaders pledged to combat climate change at the summit in Glasgow, yet Japan is already showing signs of putting the brakes on divestment from fossil fuels. Government officials have been quietly urging trading houses, refiners and utilities to slow their move away from fossil fuels, even encouraging new investments in oil and gas projects, according to people within the government and industry, who requested anonymity as the talks are private.

The officials are concerned about the long-term supply of traditional fuels as the world doubles down on renewable energy, the people said. The import-dependent nation wants to avoid a potential shortage of fuel this winter, as well as during future cold spells, after a deficit last year sparked fears of nationwide blackouts.

Japan joined almost 200 countries last month in a pledge to step up the fight against climate change, including phasing down coal power and tackling emissions. However, the moves by government officials show the struggle to turn those pledges into reality, especially for countries like Japan which relies on imports for nearly 90% of its energy and with prices spiking partly because of the world's shift away from fossil fuel investments. Japan has been slow to make concrete commitments to phase out coal in the near term, and has been criticized for funding overseas coal-fired power plants.

Australia's LNG industry at risk of running short on gas reserves

(Australian Financial Review; Dec. 3) - Australia's $56 billion-a-year LNG industry risks heading into decline without all its $200 billion of recently built liquefaction capacity ever getting fully used due to a gas shortage. Dwindling supplies have already this year affected the country's oldest LNG exporter, the 16.9-million-tonnes-a-year North West Shelf terminal, where flows from offshore fields are declining, leading to a dip in output.

One of the NW Shelf venture's five production units may close in 2024, Woodside Petroleum CEO Meg O'Neill confirmed last week. And while Woodside will build a second liquefaction train at its Pluto LNG plant as part of its $16.5 billion Scarborough gas project, the country's total LNG output may already be close to its peak, said Graeme Bethune, head of consultancy EnergyQuest.

Apart from the Pluto expansion, which is due to produce until 2055, gas reserves for northwest Australia's other six LNG ventures are all set to run out before 2050, Bethune said. The shortfall has been exacerbated by recent downgrades in gas reserves at two Woodside fields, shortening the life of the fields. At Darwin LNG, the plant will run out of gas before Santos' $4.7 billion Barossa field comes online, providing new supplies.

Queensland's northeast coast LNG industry, meanwhile, built last decade at a cost of about $80 billion, has never run at full capacity because of a lack of economic gas for Santos-led Gladstone LNG. "The trend is certainly down," Bethune said, calling for a concerted effort to commercialize the gas already discovered in scattered fields off Western Australia's coast to keep LNG plants full.

Fire shuts down production at Shell's Prelude LNG offshore Australia

(Western Australia Today; Dec. 3) - A fire late night Dec. 2 on Shell's Prelude floating LNG vessel off Australia's Kimberley coast caused production at the A$24 billion giant to be shut down and left the crew using backup power. A small fire was detected at about 11 p.m. in an electrical equipment area on the world's largest vessel. A Shell spokesman said the fire triggered automatic fire systems and was extinguished before it spread further and all workers were safe.

"Production on the Prelude has been suspended temporarily," a Shell spokesperson said. The fire comes after the 1,600-foot-long Prelude had achieved steady production for some time after a string of problems in its first few years. The Prelude was built in South Korea and towed to Australia in mid-2017, 18 months behind schedule, and did not produce LNG for another two years while problems with the complex facility were fixed. Its production capacity is 3.6 million tonnes per year of LNG.

Prelude was shut down for much of 2020 as more technical issues were addressed. Shell has never revealed how much Prelude cost, but it is understood to be at least US$17 billion ($24 billion), a 45% blowout from initial estimates. The cost overruns and delays were the principal reasons Shell, which owns 67.5% of the vessel, slashed about US$8 billion to $9 billion off the value of its Australian LNG investments in 2020. Shell in 2020 revealed it expected it would never pay for the gas it extracted at Prelude as it would never be profitable enough to make payments under the federal resource tax.

Hydropower attracts investment in Quebec aluminum smelter

(Financial Post; Canada; Dec. 1) - Rio Tinto's latest investment in a Quebec aluminum smelter is another example of how Canada's natural resources will remain an investment magnet in a more sustainable economy. Earlier this month, the metal giant announced a C$110 million investment in its aluminum smelters in Quebec — believed to be the first investment of any scale in any new North American aluminum production following about a decade of stasis, during which China's sector rose to dominance.

Rio's investment remains modest — increasing the company's aluminum production by less than 1% — but the mining giant is touting Quebec's clean hydroelectric energy and the low-emission process that it uses to smelt as a primary driver behind the expansion. "We've got hydropower, and we've got the lowest carbon aluminum smelting technology in the world," said Ivan Vella, chief executive of aluminum at Rio Tinto. "You put those pieces together and we think that's something we should invest in."

That rationale is likely to take on new life in policy discussions of how Canada can best meet its goal of reducing emissions 40% to 45% below 2005 levels by 2030 while still growing the economy. Already, the federal government has set aside $8 billion in a Strategic Innovation Fund to help decarbonize industries and has started doling out hundreds of millions of dollars to help steel, cement and other sectors cut emissions.